APPENDIX A

CCS MODELING ASSUMPTIONS

Overview

This Appendix describes the carbon capture and storage ("CCS") assumptions used in both the U.S. Environmental Protection Agency's ("EPA") Integrated Planning Module ("IPM") runs to support the proposed Carbon Pollution behalf of the Clean Air Task Force (CATF).

The purpose of the CATF modeling work was to test different CCS assumptions than those used by EPA to determine what amount of CCS retrofits or new builds, if any, would result from the proposed CPP.

Both the EPA and CATF models examine the U.S. electricity sector. EPA uses the IPM model, while the CATF runs rely on CRA's North American Electricity and Environmental Model ("NEEM"). NEEM is one of the leading models for assessing the impacts of energy and environmental policy on electricity markets.

The CATF modeling work began by re-creating in NEEM the CPP "EPA Policy Case" scenario for CO_2 emissions reductions from subpart Da and KKKK sources for the period ending 2030. In preparing the EPA Policy Case, CRA undertook the following steps to configure the NEEM model:

- Aligned demand growth rates and energy efficiency deployment in NEEM regions to EPA's CPP assumptions.
- Updated planned additions and retirements in NEEM to be consistent with data from Energy Velocity, as EPA did.
- Adopted EPA's assumptions for coal CCS retrofits.
- Updated NEEM CCS transport costs based on IPM to State Mappings.
- Adopted EPA unit and retrofit characterizations, and build availability by technology type.
- Updated fixed operation and maintenance costs ("FOM") and variable operation and maintenance costs ("VOM") for all existing units to be in line with EPA assumptions.
- Created emission regions specific to the study states from NEEM regions and imposed EPA emissions constraints.
- Adopted EPA's Henry Hub forecast & regional gas price bases.

Once the "EPA Policy Case" was successfully duplicated in NEEM, it could serve as a benchmark against which subsequent changes in the CCS assumptions could be measured. The only meaningful difference between the CATF modeling and that conducted by EPA are the CCS assumptions. This appendix is organized into the following three sections and provides a comprehensive explanation for CATF's CCS assumptions: 1) CCS Assumptions Used in the EPA Modeling Scenarios; 2) CCS Assumptions Used in EPA Modeling Scenarios are Out-of-Date and Erroneous; 3) CCS Assumptions Used in the CATF Modeling Scenarios.

I. CCS Assumptions Used in the EPA Modeling Scenarios

EPA models CCS in IPM modeling runs supporting the proposed rule using assumptions found in EPA Base Case v5.13.[1] This base case uses capture costs developed for new and retrofit plants, and combines them with storage and transportation costs developed with GeoCAT, a spreadsheet model developed by ICF to support EPA's Underground Injection Control ("UIC") rulemaking in 2008.[2]

a. EPA CO_2 Storage Costs and Volumes in EPA Base Case v5.13

GeoCAT develops commercial scale costs for storage in four of seven possible settings: saline reservoirs, depleted gas fields, depleted oil fields, and enhanced oil recovery ("EOR"). These settings are characterized by "cost curves" that reflect total sequestration capacity and annual storage volumes in each region/state at various costs.[3] GeoCAT generates these cost curves using inputs from two other modules within GeoCAT: a unit cost specification module and a project scenario costing module. The unit cost specification module consists of 120 elements; the most important contributors to cost include operation, injection well construction, and monitoring.[4] These unit costs are used to develop project scenario costs that in turn help define the cost curves.[5]

The maximum revenue from CO_2 sales for EOR in the GeoCAT model for any location in the United States is $14.52 per short ton ($2011). This is the maximum assumed revenue available to the owner of a power plant to offset the capital and operating costs of CO_2 capture equipment and CO_2 transportation costs to the EOR field. As described later in this Appendix, CATF concludes that $14.52 per short ton significantly underestimates both the maximum and typical CO_2 sales revenue available for power plants in the EOR market. Also, as described later in this Appendix, GeoCAT relied upon outdated studies to develop EOR storage volumes. Current estimates of EOR are much greater than what was estimated in 2008 when GeoCAT was first created.

b. EPA CO_2 Transportation Costs in EPA Base Case v5.13

GeoCAT also estimates transportation costs from any of the IPM regions to the storage regions in Table 6-2. These transportation costs reflect distance and differing economies based

[1] U.S. EPA, Clean Air Markets Division, *Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model*, (Nov. 2013), *available at*: http://www.epa.gov/airmarkets/progsregs/epa-ipm/BaseCasev513.html (hereinafter "*Documentation for EPA Base Case v.5.13*").

[2] *Id.* at 6-1 – 6-2. *See also* 73 Fed. Reg. 43,492 (July 25, 2008) (Proposed Rule).

[3] *Documentation for EPA Base Case v.5.13* at 6-3.

[4] *Id.* at 6-2.

[5] *Id.* at Table 6-2.

upon the quantity of CO_2 transported.[6] The costs for transporting CO_2 within Texas, for example, range in GeoCAT from between \$4.48/ton of CO_2 to \$10.41/ton of CO_2. As noted later in this Appendix, CATF believes the correct range is much lower, from as little as \$.42/ton of CO_2 to \$6.67/ton of CO_2.

c. EPA New and Retrofit CCS Costs in EPA Base Case v5.13

The costs of various technologies used in EPA Base Case v5.13 are described in Documentation for EPA Base Case v.5.13.[7] Chapter 4 identifies new CCS cost assumptions as summarized in the table below:[8]

Table 4-13 Performance and Unit Cost Assumptions for Potential (New) Capacity from Conventional Technologies in EPA Base Case v.5.13

	Advanced Combined Cycle	Advanced Combustion Turbine	Nuclear	Integrated Gasification Combined Cycle	Integrated Gasification Combined Cycle with Carbon Sequestration	Supercritical Pulverized Coal
Size (MW)	400	210	2236	600	520	1300
First Run Year Available	2016	2016	2020	2018	2020	2018
Lead Time (Years)	3	2	6	4	4	4
Availability	87%	92%	90%	85%	85%	85%
Vintage #1 (2016-2054)						
Heat Rate (Btu/kWh)	6,430	9,750	10,452	8,700	10,700	8,800
Capital (2011$/kW)	1,006	664	5,429	2,969	4,086	2,883
Fixed O&M (2011$/kW/yr)	15.1	6.9	91.7	62.3	70.6	30.6
Variable O&M (2011$/MWh)	3.2	10.2	2.1	7.2	8.2	4.4

Notes:
[a] Capital cost represents overnight capital cost.

Chapter 6 provides costs for retrofit options in the EPA Base Case v5.13. The table below summarizes these retrofit assumptions:[9]

Table 6-1 Performance and Unit Cost Assumptions for Carbon Capture Retrofits on Pulverized Coal Plants

Applicability (Original MW Size)	**> 400 MW**
Incremental[a] Capital Cost (2011 $/kW)	1,794
Incremental[a] FOM (2011 $/kW-yr)	27.2
Incremental[a] VOM (2011 (mills/kWh)	3.2
Capacity Penalty (%)	-25%
Heat Rate Penalty (%)	33%
CO_2 Removal (%)	90%

Note:
[a] Incremental costs are applied to the derated (after retrofit) MW size.

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[6] *Id.* at Table 3 (summarizing the costs for transportation).
[7] *See generally Documentation for EPA Base Case v.5.13.*

[8] *Id.* at 4-25.

[9] *Id.* at 6-1.

II. CCS Assumptions Used in EPA Modeling Scenarios are Out-of-Date and Erroneous

This section documents problems with EPA's CCS assumptions used in the IPM modeling for the CPP. The problems are categorized into four areas:

- Value of CO_2 sold into the EOR market- The GeoCAT analysis significantly underestimates the value of CO_2 that is sold for EOR.
- EOR storage capacity for CO_2 - GeoCAT outputs do not reflect recent estimates of economic EOR storage capacity. If they were included, the amount of CO_2 storage available to the power sector would double.
- CO_2 transportation costs are overestimated.
- Retrofit and new build options were limited in EPA Base Case v5.13 - Consequently, CO_2 capture costs may have been overstated.

a. Value of CO_2 Sold into the EOR Market

The GeoCAT analysis significantly underestimates the value of CO_2 sold for EOR. EPA's estimates of EOR revenues and economic storage volumes - critical to modeling future electric generating unit ("EGU") retrofits and new builds - are unrealistically low. This is largely because EPA relied on a 2008 analysis that was not updated for the CPP. As discussed below, assumptions from 2008 undervalue the price of oil and current prices of CO_2, and overestimate the costs of current regulatory requirements. The end result is that the outdated analysis underestimates revenue streams back to EGU capture projects.

The maximum EOR storage step price established by ICF and used in GeoCAT is -$14.52 per short ton - this is the maximum price that a CO_2 emitter would receive from a storage facility (negative values mean received revenue) for one ton of CO_2. The GeoCAT values for CO_2 per ton available from EOR storage is low by roughly half or more in some areas. For example, in the West Texas Permian Basin (where CO_2 is supply limited) and Wyoming, contracts for CO_2 are approximately $40 per metric tonne ($36 per short ton).[10]

A more defensible and widely accepted way to estimate the value of CO_2 is that the cost of CO_2 in MCF is about 2 percent of value of a barrel of oil ("bbl") and as expressed in short tons. Given that one short ton of CO_2 is approximately equivalent to 17.5 MCF, at an oil price of $100/bbl one ton of CO_2 would cost $35/ton. At $80/bbl the value for one ton of CO_2 is $28. Several investigations support this approach. According to Cook (2011) the operational supply of CO_2 in Wyoming was estimated to be $2.17/ MCF assuming: a) $83.45/bbl and b) that CO_2 is

[10] $40 per metric tonne CO_2 price assumption is further supported by Phil DiPietro, NETL, *Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next-Generation" CO_2 Enhanced Oil Recovery (CO2-EOR),* (June 20, 2011), *available at*: http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/DOE-NETL-2011-1504-StoringCO2-wEOR-Final.pdf, and Michael L. Godec, Advanced Resources International, Powerpoint, *From CO_2-EOR to CCS:* "*Prospects and Challenges of Combining CO_2-EOR with Storage*," IEA-OPEC CO_2-EOR Kuwait Workshop (Feb. 2012), *available at* http://www.iea.org/media/workshops/2012/ieaopec/Godec.pdf.

tied at 2 percent of the oil price plus a $0.50 transportation charge.[11] Van't Veld and Phillips similarly conclude that the value of per MCF of CO_2 in West Texas, East New Mexico and Utah region can be estimated by 2.5 percent times the price of a barrel of oil plus a 0.50 transportation charge.[12] In the Gulf Coast states, the cost factor for CO_2 is reportedly less presumably due to the large supply of naturally mined CO2 from the Jackson Dome. There, a ton of CO_2 may be tied to approximately 1.25 times the price of a barrel of oil, yielding a price of approximately $22 per short ton of CO_2.

There are two fundamental reasons why EPA may have established too low a payment for CO_2:

- The price of oil in 2008 was $56 per barrel, far less than the $80 -$100 per barrel price experienced in recent years or the range of future prices. The price range used in GeoCAT for EPA Base Case v5.13 therefore understates the value of CO_2; and
- The GeoCAT model is based on overestimated storage costs and UIC Class VI permitting which is not required in EOR fields. These higher storage costs reduce the price per ton of CO_2 paid supplier under GeoCAT's EOR assumptions.

These two findings are detailed below:

i. The price of a barrel of oil EPA uses is too low.

The GeoCAT analysis assumes a price per bbl of $56 from the 2008 Annual Energy Outlook. The table below illustrates the expected values of CO_2 at a variety of oil prices. Over the one-year period ending in November 2014 the price of West Texas intermediate crude has varied between approximately $81 and $105. In the US Energy Information Administration's 2014 forecast, the low oil price case to 2040 is approximately $70 per barrel whereas the high oil price case is about $204 per barrel in 2040.[13] This means that the projected future byproduct credit assigned is too low in GeoCAT and therefore the resulting cost of storage is too high. For example, at a conservative utilization rate of 2.5 bbls produced per ton of CO_2 injected, an $80 per bbl (the current price) would produce $200 in revenue, as compared with $140.

	Oil Price $/bbl	CO_2 Price $ per Short ton
Used by EPA in GeoCAT, 2008	$56	$20
Bottom of EIA range to 2040	$70	$25
Late 2014 WTI Crude	$80	$28

[11] Benjamin R. Cook, *The Economic Contributions of CO_2 Enhanced Oil Recovery in Wyoming's Economy* (June 2012) *available at*: http://www.uwyo.edu/cee/_files/docs/cook-benjamin-economic-contribution-co2-eor.pdf.

[12] Klaas van't Veld and Owen R. Phillips, *Pegging Input Prices in Long Term Contracts: CO_2 Purchase Agreements in Enhanced Oil Recovery* (July 2009) *available at*: http://www.uwyo.edu/owenphillips/papers/co2pegging071509.pdf.

[13] U.S. EIA, *Annual Energy Outlook*, at E-9 (2014).

Early to Mid 2014 WTI Crude	$100	$35
Midpoint of EIA range to 2040	$137	$48
Upper Range of EIA to 2040.	$204	$71

Range of CO_2 prices per short ton with a ton of CO_2 tied to two percent of the price of a barrel of oil. EIA prices from 2014 report.[14]

ii. EPA Overestimates Storage Costs.

The GeoCAT model runs, as described in Vidas *et al.* (2009)[15], are premised on storage cost assumptions from the UIC rule Class VI requirements.[16] This is incorrect because CO_2 EOR storage with concurrent production is allowable under EPA's Class II rules, and the Class VI rules do not require a transition to Class VI permitting unless a transition is required by a two-part trigger: a) the primary purpose is changed to storage, and b) there is increased risk relative to Class II business as usual operations.[17] EOR operators undertaking storage for the primary purpose of oil production with incidental storage may operate under Class II and report under the Greenhouse Gas Reporting Rule Subpart RR (which was finalized in late 2010 and did not exist at the time of the 2008 GeoCAT modeling effort).[18] The stringency of the Class VI rules is much greater than Class II. The cost of complying with RR is very small. For this reason the model runs for the purposes of the current rule should not be utilized to assess the costs of CO_2 storage in EOR environments.

The Class VI-based analysis combined with other incorrect assumptions made by Vidas *et al.* (2009) may have reduced the estimated available geologic storage and limited the modeled retrofits of existing plants and construction of new plants with CCS. For example: 1) Costs for geologic site characterization in depleted oil and gas fields are shown to be substantially higher for depleted oil and gas fields than for saline storage. Depleted fields have proven geologic seals, known reservoir capacity proportional to historical production, and existing subsurface data such as logs. If seismic profiling were needed, it would be much less costly than for saline; 2) Well costs seem to be heavily weighted. Well operation costs appear high; 3) Monitoring for depleted oil and gas fields is four times that for saline. Costs in depleted oil fields should be less since the plume and pressure areas are well known, as they are managed via production.

b. EPA Does Not Account for All Available EOR Storage Capacity for CO_2

[14] *Id*.

[15] Harry Vidas *et al.*, Analysis of sequestration costs for the United States and implications for climate change mitigation, 1 ENERGY PROCEDIA 4281-4288 (2009) (Appx. A, Ex. 1).

[16] 76 Fed. Reg. 56,982 (Sept. 15, 2011).

[17] 40 C.F.R. § 144.19.

[18] 75 Fed. Reg. 75,060 (Dec. 1, 2010).

Recent estimates of economic EOR storage capacity are not reflected in GeoCAT outputs. If they were included, the amount of CO_2 storage available to the power sector would double.

From EPA's *Documentation for EPA Base Case v.5.13*, a total of 13.35 Gt of storage and depleted oil fields is possible with net positive revenue.[19] This number is underestimated by a factor of approximately two. Since the 2008 development of GeoCAT, estimates of CO_2 demand and producible oil have increased based on new "next generation" technologies for CO_2 flooding.[20] Moreover, numerous fields are now flooding residual oil zones ("ROZ") below existing fields not previously recognized (e.g. Hess Seminole and Kinder-Morgan SACROC fields in the West Texas Permian Basin.). In fact, in some areas there are reserves available through CO_2 flooding where there is no main pay zone as a "greenfield ROZ". The estimates of available storage have not taken these into account.

According to Advanced Resources International ("ARI") (2012), next-generation CO_2 EOR, including ROZ, could produce 176 billion technical bbls recoverable at $85 per barrel and with an associated CO_2 demand and storage capacity 62 metric Gt (68 billion short tons).[21] Of this, National Energy Technology Laboratory ("NETL") estimates that 100 million barrels would be economically recoverable and demand 33 billion metric tons (36 billion short tons) of CO_2. Of this amount approximately 3 metric Gt (3.3 billion short tons) would come from natural sources and natural gas separation plants with a net available storage of 30 metric Gt (33 billion short tons).

DiPietro *et al.* (2012) provide the most recent estimates of natural and industrial CO_2 that may be utilized before CO_2 captured from power plants. Starting with the ARI (2012) estimate of 33 Gt (metric tonnes) total CO_2 demand, and reducing that amount by 2.2 Mt of natural CO_2 and 5.6 Mt of CO_2 from natural gas separation, approximately 25 Gt of storage in EOR fields are available, approximately double the 13 Gt as reflected in the total volumes estimated by EPA in Table 6.2 of the *Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model*.

CO_2 storage volumes may also have been underestimated by GeoCAT EPA Base Case v5.13 because the assumption in the GeoCAT model that EOR projects will preferentially utilize industrial sources of CO_2 for EOR prior to EGU sources. While this is generally true, in some cases utilization of more proximal EGU sources may be more cost effective. For example for the three active U.S. EGU capture projects CO_2 will be used in EOR fields: 1) Mississippi Power's Kemper County Radcliffe plant has a contract with Denbury Resources to send the CO_2 to its Heidelberg Field;[22] 2) the Texas Clean Energy Project in Odessa, Texas will provide CO_2 to

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[19] *Documentation for EPA Base Case v.5.13*, at Table 6-2.

[20] DiPietro, *Improving Domestic Energy Security and Lowering CO_2 Emissions with "Next-Generation" CO_2 Enhanced Oil Recovery (CO2-EOR).*

[21] Vello Kuuskraa, Powerpoint, *Using the economic value of CO2 EOR to accelerate the deployment of CO_2 capture, utilization and storage* (CCUS) (Apr. 25-26 2012) (Appx. A, Ex. 2).

[22] MIT "Kemper County IGCC Fact Sheet: Carbon Dioxide Capture and Storage Project," *available at*: http://sequestration.mit.edu/tools/projects/kemper.html.

nearby EOR projects such as Whiting Petroleum's North Ward Estes field;[23] 3) Petra Nova EOR Project is taking CO_2 captured from a 250 MW slipstream at NRG's W.A. Parish Plant in Thompsons Texas.[24]

c. EPA Overestimated Transportation Costs

The derivation of transport costs for the EPA Base Case v5.13 are described in section 6-3 of the *Documentation for EPA Base Case v.5.13 Using the Integrated Planning Model*.25 To estimate these costs, EPA generated a matrix of estimated pipeline transport distance from CO_2 production regions to CO_2 storage regions.26 EPA's production regions are the same as its IPM model regions. This approach did not take into account actual distances between CO_2 utilization and sources. Instead the CO_2 comes from a region where it is delivered to one point in the state rather than to the actual unit being modeled. This method also took into account that longer distance pipelines may collect other sources that share in the transportation cost.

As described later in this Appendix, CATF adopted a more transparent approach to estimating transportation costs that relied on measured distances between plants and storage regions.

d. Retrofit and New Build Options Were Limited in EPA Base Case v5.13 Because of Inaccurate Assumptions

Due to the inaccurate assumptions underlying the EPA Base Case v5.13, CO_2 capture costs may have been overstated. Therefore, the IPM model runs used to support the CPP had limited options for new builds with CCS as well as CCS retrofits to existing plants.

Coal plants in the IPM runs could only implement 90 percent capture. Partial CCS (50%) was not an available option under the model. This is important because many of the reasons for not considering partial capture as part of the best system of emission reductions underlying the state targets cited by the EPA were based on both availability and cost. Yet partial capture was not studied in the model runs, so these conclusions were untested.

Furthermore, the retrofit option for coal plants in the model was limited to units greater than 400 MW. A better evaluation of CCS retrofits would have considered costs as a function of plant size, heat rate and the type of coal burned.

For new plants, the model runs were limited to a single new coal plant CCS option-integrated gasification combined cycle ("IGCC") with 90 percent CCS. The modeling should

[23] Summit Power, "Texas Clean Energy Project," *available at*: http://www.texascleanenergyproject.com.

[24] MIT, "W.A. Parish Nova Fact Sheet: Carbon Dioxide Capture and Storage Project," *available at*: https://sequestration.mit.edu/tools/projects/wa_parish.html.

[25] *Documentation for EPA Base Case v.5.13*, at Chapter 6.

[26] *See generally Documentation for EPA Base Case v.5.13*.

have also considered partial capture and included both partial and full capture for new conventional coal plants.

Finally, no CCS option was available for gas plants either as new builds or as retrofits to existing plants.

III. CCS Assumptions Used in the CATF Modeling Scenarios

CATF retained CRA to evaluate the economic competitiveness of CCS as a CPP compliance option for "CCS-Ready" states where CO_2 captured at power plants can be used for EOR. CRA engaged in a multi-step process to evaluate CCS as a compliance option in three target states- Texas, Oklahoma, and Mississippi.

CRA configured the fundamental power market model ("NEEM") to reflect, to the extent possible, the modeling assumptions used by the EPA in their CPP modeling.

Next, CRA configured a CATF case based on the EPA Policy Case that altered only key assumptions describing CCS. In updating CCS assumptions, CATF opted for changes that we deemed to be reasonable, consistent with the general approach outlined by EPA in setting building blocks for BSER that underlie the state targets.[27] The "World 1: Updated Retrofit and EOR Assumptions" uses the same identical assumptions as the "EPA Policy Case" described above except for:

- EOR storage capacity and price
- CO_2 transportation costs
- CO_2 capture costs and options

These three categories of changes are detailed below as well as the assumptions behind the "World 5: High Gas Price" scenario.

a. EOR Storage Capacity and Price in CATF Modeling

For the modeling conducted for by CRA, CATF developed the following EOR price assumptions:

For World 1, 2, 4 and 5 CATF used -$34.32 per short ton of CO_2 for the Permian Basin in Texas and as the maximum value for CO_2 in New Mexico.[28] These prices correspond to the value of CO_2 at approximately $100 per barrel. For the rest of the U.S., the highest price for EOR

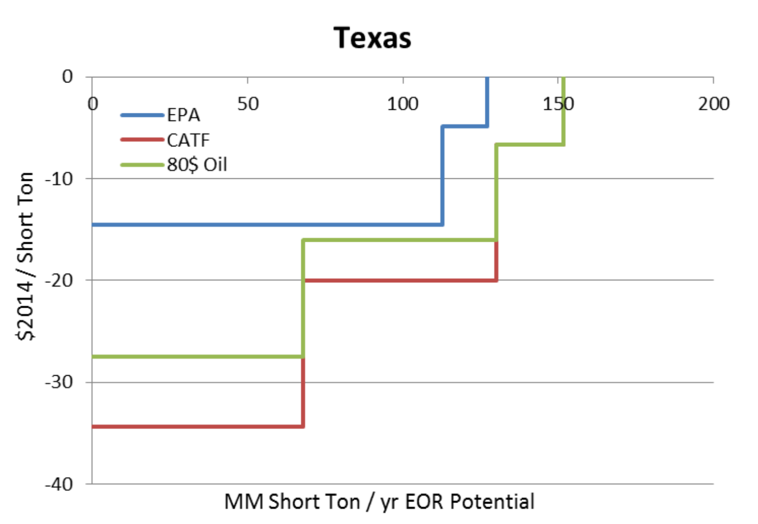
[27] 79 Fed. Reg. at 34,836 (EPA sought a BSER that was consistent with strategies, actions and measures that companies and states are already undertaking to reduce GHG emissions and with current trends in the electric power sector, driven by efforts to reduce GHGs as well as by other factors, such as advancements in technology and achieving significant and technically feasible reductions of CO_2 at a reasonable cost).

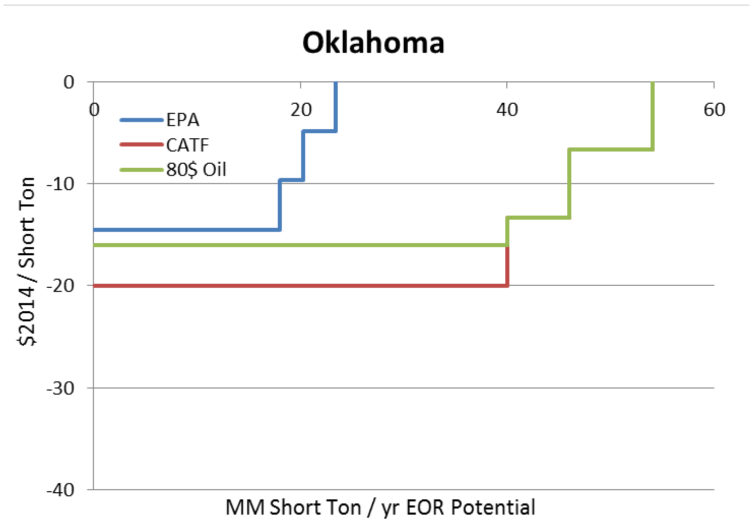
[28] These values are consistent with the paper developed by CATF: *How Much Does CCS Really Cost?*, (Dec. 2012), *available at*: http://www.catf.us/resources/whitepapers/files/20121220-How_Much_Does_CCS_Really_Cost.pdf.

was set at -\$20 per short ton of CO_2. This lower value represents CATF's understanding of the EOR market based upon input from developers, consultants, and oil companies involved in EOR.

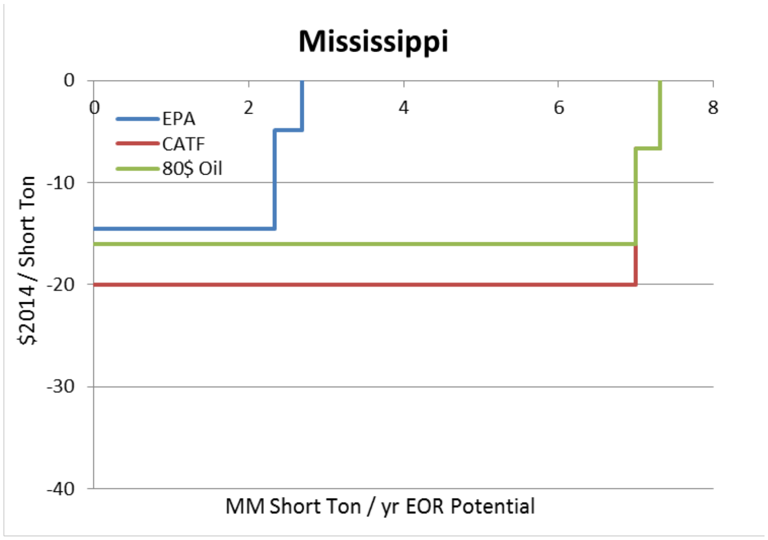
For World 3, CATF assumed CO_2 prices based upon \$80 per bbl. For the maximum price in the Permian Basin and New Mexico, this corresponds to -\$27.46 per short ton of CO_2. In the rest of the U.S., CATF assumed the maximum price was -\$16.00 per short ton of CO_2.[29]

As noted earlier, CATF estimates that the EPA Base Case v5.13 underestimates EOR capacity significantly. However, CATF only updated the EPA Base Case v5.13 for just three states Texas, Oklahoma and Mississippi. The figures below show the impact of the price and supply adjustments made by CATF to the supply curves for these three states.





[29] In some of the model results, these maximum EOR price in each state or region is described as "tier 1" or "t1" in some figures.



The revised Table 6.2 for supply and price assumptions relative to EPA Base Case v5.13 for all regions and states in the U.S. is attached at the end of this Appendix as Table 2.

b. CO_2 Transportation Costs Used in CATF Modeling

The assumptions developed for the CATF modeling took a more detailed approach to estimating costs of transport for CO_2 relative to the EPA IPM runs. First, the costs used by CATF and the EPA Base Case v5.13 share the same initial cost inputs shown below:

CARBON DIOXIDE PIPELINES

Outside Dia. Inches	Inside Dia. Inches	Wall Thickness Inches	Pipeline Cost in $/Inch-Mile	Total Cost of Service in $/metric ton per 75 miles or 121 km	Flow Capacity in metric tons/day	Flow Capacity in million standard cubic feet per day (60 degrees F and 14.73 psi)	Number of 500 MW IGCC plants accomodated
12.75	12.0	0.39	$ 51,694	$3.21	10,775	203	0.97
16	15.0	0.49	$ 56,453	$2.56	19,139	361	1.73
24	22.5	0.73	$ 62,202	$1.65	53,385	1,007	4.83
30	28.2	0.92	$ 65,002	$1.31	93,887	1,771	8.49
36	33.8	1.10	$ 67,803	$1.10	148,913	2,808	13.46
42	39.4	1.28	$ 70,603	$0.97	219,942	4,148	19.88

Note: 500 MW IGCC plant would produce 512 metric tonnes of CO2 per hour. Of this, 90% or 461 tonnes would be captured. Maximum CO2 tranport needs would be 11,064 tonnes per power plant per day.

Spacial Assumptions for Simple Average	Miles	$/Mile per Tonne	Cost per Tonne	Annual Cost per Power Plant @85 Utilization Rate
Single Power Plant Pipeline (12 inch, small gathering) distance in miles	25	$0.043	$1.07	$3,674,799
Two Power Plant Pipeline (16 inch, large gathering) distance in miles	25	$0.034	$0.85	$2,923,774
Eight Power Plant Pipeline (30 inch, mainline) distance in miles	100	$0.017	$1.75	$5,999,775
Total Distance & Costs	150	$0.024	$3.67	$12,598,347

In Texas, Mississippi and Oklahoma, the latitude and longitude of each unit 200 MW or greater was used to estimate the distance to the nearest EOR storage site in EOR.

Study Region	EOR Basins
Texas	Permian, TX, NM, OK
Mississippi	Permian, MS, LA, IL, TX, OK
Oklahoma	Permian, TX, OK, NM

Each unit has multiple transport costs, one associated with each basin to which it is mapped

Tier	Estimated Distance to Basin	Assumed pipeline distance (miles)	Assumed Pipe diameter (inches)	Assumed Transport Cost (2011$/ per short ton)
1	0 miles	N/A	N/A	0.42
2	1-10 miles	10	12	0.42
3	10-25 miles	25	12	1.05
4	25-50 miles	50	12	2.11
5	50-100 Miles	100	16	3.34
6	100-200 Miles	200	16	6.47
7	200-300 Miles	300	24	6.67
8+	+100 Miles	+100 Miles	24	+2.16

The fine scale analysis illustrates how the costs in EPA's IPM runs may be significantly overestimated. Relative to cost in the detailed study, the average CATF Texas cost ranged from $.42 to $6.67 with an average cost of $2.47, compared to EPA's Texas cost of $4.48 to $10.41 depending on EPA source region. For Oklahoma, the average CATF estimated cost ranged from a minimum of $0.42 to a maximum of $2.11 with an average of $0.69 compared to a range of $4.76 to $6.48 depending on EPA's source region.

The table below compares and summarizes the key similarities and differences between the CATF modeling and the IPM runs used by EPA to support the CPP.

	EPA IPM Runs Base Case v5.13	CATF NEEM World 1	CATF NEEM World 2	CATF NEEM World 3	CATF NEEM World 4	CATF NEEM World 5
Maximum Price Paid for CO_2 with EOR ($/short ton) (1)						
Permian Basin	14.52	34.32	World 1	27.46	World 1	World 1
New Mexico	14.52	34.32	World 1	27.46	World 1	World 1
Texas Outside Permian Basin	6.67	13.33	World 1	16	World 1	World 1
Oklahoma	14.52	20	World 1	16	World 1	World 1
Mississippi	14.52	20	World 1	16	World 1	World 1
Rest of Nation	14.52	20	World 1	16	World 1	World 1
EOR Capacity (Million Short tons) (2)						
Permian Basin	5,633	3,104	World 1	World 1	World 1	World 1
New Mexico	672	672	World 1	World 1	World 1	World 1
Texas Outside Permian Basin	724	3,896	World 1	World 1	World 1	World 1
Oklahoma	1,168	2,545	World 1	World 1	World 1	World 1
Mississippi	135	317	World 1	World 1	World 1	World 1
Rest of Nation	5,214	5214	World 1	World 1	World 1	World 1
National Total	13,546	15,748	World 1	World 1	World 1	World 1
Transportation (2)						
Texas	GeoCat Table 6-3	For each plant over 200 MW, calculated distance to basins and calculated pipeline costs.	World 1	World 1	World 1	World 1
Oklahoma	GeoCat Table 6-3	For each plant over 200 MW, calculated distance to basins and calculated pipeline costs.	World 1	World 1	World 1	World 1
Mississippi	GeoCat Table 6-3	For each plant over 200 MW, calculated distance to basins and calculated pipeline costs.	World 1	World 1	World 1	World 1
Rest of Nation	GeoCat Table 6-3	GeoCat Table 6-3	World 1	World 1	World 1	World 1
CO_2 Capture (2)						
Coal Retrofits	1 case- greater than 400 MW, 90%	15 cases based upn heat rate,50% or 90% capture level, and unit size	EPA Base Case v5.13	World 1	World 1	World 1
Gas Retrofits	No	Yes-90%	EPA Base Case v5.14	World 1	World 1	World 1
Coal New Builds	1 case- IGCC 90%	8 cases based on coal type, PC and IGCC, 90% and 50% capture	EPA Base Case v5.15	World 1	World 1	World 1
Gas New Builds	No	Yes-90%	EPA Base Case v5.16	World 1	World 1	World 1
Greenfield CCS Plants Count as Compliance Option for CPP?	No	No	No	No	Yes	No
Gas Prices (2)	EPA Base Case v5.13	EPA Base Case v5.14	EPA Base Case v5.15	EPA Base Case v5.16	EPA Base Case v5.17	AEO 2012 low O & G supply
Notes						

1. $14.52 per short ton is the maximum price GeoCAT pays for EOR anywhere in the nation EPA Base Case v5.13. This corresponds to STEP 1 in Table 6-2 for the GeoCAT model. Other EOR prices ($/short ton) include STEP 2 is 9.68; STEP 3 is 4.84, and STEP 4 is $0. See Appendix ___ for CATF STEP prices and storage.
2. See Appendix ___ for detailed discussion of CATF storage capacities, transportation coststs, CO_2 capture costs, and gas prices.

c. CO_2 Capture Costs Used in CATF Modeling

CATF developed a range of retrofit and new plant CCS costs. Under the World 1 and 3-5 scenarios, coal units can choose both 50 percent and 90 percent retrofit options at size increments of between 200-400MW, 400-600MW, and >600MW. Gas fired units may install 90 percent capture technology.

For new build plants, the model represents eight coal CCS options (4 fuel / technology combinations at 50% and 90% capture) and gas-fired 90 percent capture option.

These assumptions are summarized in "Table 1: New Build and Retrofit Assumptions Developed and Used By CATF" found at the end of this Appendix.

i. Description of CO_2 Capture Performance and Cost Estimates

The CATF estimates for the cost and performance of new natural gas and coal-fired power plants included both cases of plants with and without CO_2 capture.[30] These included the cost and performance impacts of retrofit of CO_2 capture to existing gas and coal-fired power plants, for use in a separate power fleet model of the U.S. Gulf Coast region.

New build unit types included in the analysis are:

- Large new natural gas combined cycle ("NGCC") with 0 percent and 90 percent CO_2 capture
- Large new IGCC using bituminous coal, with 0 percent, 45 percent, and 90 percent CO_2 capture
- Large new supercritical pulverized coal ("SCPC") utilizing bituminous coal, Power River Basin ("PRB" sub-bituminous) coal, and lignite, with 0 percent, 50 percent, and 90 percent CO_2 capture

These unit types were selected in part due to the availability of three detailed prior techno-economic studies produced by the NETL.[31] These three studies use the same cost baseline (June, 2007) and performance modeling parameters and assumptions, and form an internally

[30] CO_2 "capture" here refers to separation of CO_2 from the exhaust gases (or, in the case of IGCC, from the synthesis fuel gas) of a power plant, and preparation (e.g., purification and compression) of that CO_2 for delivery to a transportation pipeline for later sales or other uses (*e.g.*, geological sequestration). The term as used here does not include long-distance transportation of captured CO_2, sequestration, or other uses.

[31] Kristin Gerdes, NETL, *Cost and Performance of PC and IGCC Plants for a Range of Carbon Dioxide Capture*, Revision 1, (Sept. 19, 2013) *available at*: http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Publications/Gerdes-08022011.pdf; James B. Black, NETL, *Cost and Performance Baseline for Fossil Energy Plants Volume 3b: Low Rank Coal to Electricity: Combustion Cases*, (Mar. 2011) *available at*: http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/Coal/LR_PCCFBC_FR_20110325.pdf; James Black, NETL, *Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity Revision 2*, (Nov. 2010) *available at*: http://www.netl.doe.gov/File%20Library/Research/Energy%20Analysis/OE/BitBase_FinRep_Rev2a-3_20130919_1.pdf.

consistent data set upon which to build. The November 2010 has been updated recently, but that update was not used here in order to ensure consistency with the other studies. For these new builds data on the 50 percent capture level for PRB and lignite was not available in the NETL studies, so estimates were developed here based on the results of the 50 percent capture level reported by NETL for bituminous coal.[32] Due to data availability in the NETL studies, the new NGCC and bituminous coal units are assumed to use wet cooling towers, while the new PRB and lignite units are assumed to use 50/50 hybrid wet/dry cooling.[33]

For the new build unit types, all cost estimates have been updated from the June 2007 levels presented by NETL to June 2013 levels using published Chemical Engineering Plant Cost Index values (532.7 and 563.0, respectively).[34] Costs included here are construction ("TOC") costs[35], FOM costs, and VOM costs. Neither fuel costs nor financing costs are estimated here. An allowance for revenue from sales of CO_2 near the plant gate at $35 has been included as a separate item under VOM costs, however.

Apart from updating the cost basis there have been no significant changes to the NETL estimates for the new build cases, except for the 50 percent capture level on PRB and lignite SCPC units. NETL study data was not available for 50 percent capture on those types of units, so estimates were derived here based on NETL study data for partial capture levels on new SCPC units burning bituminous coal.[36] The NETL study data indicate that for new units both heat rate and construction cost are nearly linear functions of CO_2 capture levels between 0 percent and 90 percent. Hence, to derive performance and cost estimates for new SCPC units burning PRB and lignite with 50 percent CO_2 capture, simple interpolation on heat rate and TOC were used. FOM and VOM were assumed to follow the same trend as TOC.

For CO_2 capture retrofits, this analysis includes:

- Large (> 250 MW), relatively efficient (> 45% on HHV basis) existing NGCC, retrofit with 90% CO_2 capture
- Existing coal units of all sizes and fuel types, retrofit with 50% and 90% CO_2 capture

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[32] It is worth noting that the CO_2 emission rates derived here for new PRB and lignite SCPC units with 50% CO_2 capture may exceed eventual EPA emission standards. If those standards, when final, indicate that slightly greater than 50% capture would be required for PRB and lignite units, the incremental cost difference for use in a fleet modeling exercise is expected to be small.

[33] Similarly, although NETL study data on IGCC using PRB and lignite are available, those cases are based on operation at higher elevations, which may affect IGCC performance in a way that renders the data inapplicable to the US Gulf Coast context.

[34] Scott Jenkins, "Current Trends," CHEM. ENG'G (Dec. 1, 2014) (Appx. A, Ex. 3).

[35] Construction costs are expressed as total overnight costs, or "TOC", including site preparation, materials, equipment, installation labor, engineering construction management, contingencies, and owners costs (e.g., land), but not including interest during construction or escalation. *See* Black, *Cost and Performance Baseline for Fossil Energy Plants Volume 1*, *supra* note 32 at 9.

[36] *See* Gerdes, *supra* note 32.

Estimates of the impact of CO_2 capture retrofit on NGCC units was derived from NETL studies of new NGCC with and without 90 percent CO_2 capture,[37] which indicates that installation of CO_2 capture on NGCC of this type leaves many plant systems unchanged (e.g., gas turbine, heat recovery steam generator, high pressure and intermediate pressure steam turbines). As a result, the performance and cost impacts of retrofit of 90 percent CO_2 capture on existing NGCC of this type has been estimated here simply by the difference in performance, and associated incremental cost, of new NGCC with 90 percent CO_2 capture compared to the same NGCC without CO_2 capture in NETL's study.[38] Because the NETL study data is based on NGCC utilizing larger, modern equipment, a restriction to generally similar units has been applied to this analysis (units with a combined cycle capacity greater than 250 MW and a pre-retrofit efficiency greater than 45% HHV efficiency).

NETL study data on retrofit of CO_2 capture to existing coal units is sparse compared to study data for new units. Additionally, examination of the impact of CO_2 capture on unit performance is more involved for coal-burning units than NGCC because the amount of CO_2 to be captured (and consequently the energy penalty) is more pronounced, the exhaust gases contain higher levels of impurities, and all of the unit power comes from the steam cycle, rather than from a gas turbine which is unaffected by the capture retrofit. Consequently, in this analysis for existing coal the generalized CO_2 capture retrofit impact parameters used by EPA in their IPM model have been adopted[39] subject to the same cost basis-year updates as are used here for new units, with two important modifications:

In addition to the 90 percent CO_2 capture level assumed by EPA, an estimate for a 50 percent capture level has been developed here. An NETL study of 30 percent, 50 percent, 70 percent, and 90 percent CO_2 capture retrofit to an existing 434 MW coal unit (which itself forms part of the basis for EPA's estimate) indicates that both the energy penalty of the capture retrofit (assessed in this instance as the reduction in unit output given a constant level of fuel consumption) and TOC are both roughly linear functions of the capture level, especially near the 50 percent capture point. Hence in the same manner as for new units, in this analysis the performance impact (unit output reduction) and construction cost of 50 percent CO_2 capture is estimated by simple interpolation.

EPA's "one-size-fits-all" approach to CO_2 capture retrofit costs has been modified to reflect a potential dependence of capture system costs on size.[40] Due to a scarcity of data, in this

[37] Black, *Cost and Performance Baseline for Fossil Energy Plants Volume 1*, *supra* note 32.
[38] According to the NETL study, due to diversion of steam for regeneration of amine solvent used for CO_2 separation the mass flow of steam to the low pressure turbine portion of the existing NGCC may fall by approximately one half upon retrofit of 90% CO_2 capture. *Id.* at Exhibits 5-11 and 5-22. Because this may create challenges for continued operation of that turbine, for conservatism in this analysis the difference in steam turbine system costs between NGCC without and with NGCC with 90% CO_2 capture in has not been credited to the retrofit, while 50% of the cost of the steam turbine for the 90% CO_2 capture case has been added. This is intended to provide an approximation of the cost of replacing the existing low-pressure steam turbine in the NGCC with a smaller one upon CO_2 capture retrofit, should this prove necessary.

[39] *Documentation for EPA Base Case v.5.13*, at 6-1.

[40] The "six-tenths" size scaling has not been applied to new coal units because specific data has been developed for the specific size units to be allowed in the fleet model. No size scaling has been applied for NGCC retrofits because

analysis the "six-tenths" engineering rule of thumb has been applied, in which the unknown cost at some system size (measured in tons per day of CO_2 captured and compressed) is estimated as the known cost at some other system size multiplied by the ratio of the system sizes raised to the power 0.6. The known size and cost used here were chosen to match IPM (a 400 MW unit of average efficiency retrofit with 90% CO_2 capture, yielding 9299 tpd of CO_2, at a 2011 cost of \$1794/kW-net after retrofit). To facilitate use in the fleet model, the CO_2 capture system cost dependence on size has been presented in tabular form by category of existing unit for three pre-retrofit capacity ranges[41] and three pre-retrofit heat rates.[42]

much of the CO_2 capture equipment in the NETL studies is already applied on a per-stack basis to each combustion turbine. *See e.g.*, Black, *Cost and Performance Baseline for Fossil Energy Plants Volume 1*, *supra* note 32 at 488-489.

[41] 100 MW – 300 MW, represented by a 200 MW unit; 300 MW – 600 MW, represented by a 400 MW unit; and 600+ MW, represented by an 800 MW unit.

[42] Less than 10000 Btu/kWh, represented by a 9500 Btu/kWh unit; between 10000 Btu/kWh and 11000 Btu/kWh, represented by a 10500 Btu/kWh unit; and greater than 11000 Btu/kWh, represented by an 11500 Btu/kWh unit.

d. Gas Price Assumptions in CATF Modeling for World 5

The figure below shows the high gas price data used in World 5.